RESULTS OF OPERATIONS

As used in this section, references to increases and decreases, whether in terms of amounts or percentages, are made by comparison of the three months ended March 31, 2010 to the three months ended March 31, 2009.

Revenues

Three months ended March 31 (Canadian dollars in millions)	2010	2009	$ Change	% Change
Transmission	320	302	18	6
Distribution	983	986	(3)	-
Other	16	15	1	7
	1,319	1,303	16	1
Average Ontario 60-minute peak demand *(MW)*[1]	20,935	22,186	(1,251)	(6)
Distribution - units distributed to customers *(TWh)*[1]	8.0	8.4	(0.4)	(5)

[1]System-related statistics are preliminary

The demand for electricity generally follows normal weather-related variations, and therefore our energy-related revenues, all other things being equal, will tend to be higher in the first and third quarters than in the second and fourth quarters.

Transmission

Transmission revenues predominantly consist of our transmission tariff, which is based on the monthly peak demand for electricity across our high-voltage network. The tariff is designed to recover revenues necessary to support a transmission system with sufficient capacity to accommodate the maximum expected demand. Demand is primarily influenced by weather and economic conditions. Transmission revenues also include export revenue associated with transmitting excess generation to surrounding markets and ancillary revenues which are primarily attributable to maintenance services primarily provided to generators and secondary use of our land rights-of-way.

Our transmission revenues were higher by $18 million, or 6%, in the first quarter of 2010 compared to the same period last year. This increase was mainly due to the Ontario Energy Board (OEB)-approved transmission tariff rate increases that were effective July 1, 2009 and January 1, 2010 and resulted in higher revenues of $30 million. The increase in transmission rates supports investments made in respect of the Ontario Power Authority's (OPA) supply mix policy, including the phase-out of coal-fired generation and investments to address aging infrastructure. These increases were partially offset by decreased revenue associated with the lower average annual Ontario 60-minute peak demand and the lower overall related load, which was lower by $17 million when compared to the same period last year.

Higher ancillary revenues of $5 million also contributed to the increase.

Distribution

Distribution revenues include our distribution tariff, and amounts to recover the cost of purchased power used by our customers. Accordingly, distribution revenues are influenced by the amount of electricity we distribute, the cost of purchased power and our distribution tariff rates. Distribution revenues also include a minor amount of ancillary distribution services revenues, such as fees related to the use of our poles by the telecommunications and cable television industries, and miscellaneous charges such as those for late payments.

Distribution revenues decreased by $3 million in the first quarter of 2010 compared to the same period last year. Reductions in revenues were primarily due to lower energy consumption and the recovery of lower purchased power costs. Lower energy consumption, primarily from milder weather, resulted in a reduction in distribution revenue by $14 million. The recovery of lower purchased power costs reduced distribution revenue by $11 million, as described below under "Purchased Power."

Distribution revenue reductions were partially offset by increases in the distribution tariff rates for our subsidiary, Hydro One Networks Inc., resulting from the December 18, 2008 OEB decision on our cost of service application and from the May 13, 2009 OEB decision in respect of our rate application under the third generation Incentive Rate Mechanism (IRM). These rate increases, which were effective on May 1, 2008 and May 1, 2009, respectively, resulted in higher distribution revenues of $12 million and will support the maintenance and investment requirements of our distribution system and enable the safe and

reliable delivery of electricity to our customers throughout Ontario. The third generation IRM decision also resulted in increased revenue related to the recovery of smart meter investments of $7 million.

In addition, ancillary revenues were higher by $3 million as compared to the same period last year.

Purchased Power

Purchased power costs incurred by our Distribution Business represent the cost of electricity delivered to customers within our distribution service territory and consist of the wholesale commodity cost of energy, the Independent Electricity System Operator's (IESO's) wholesale market service charges, and transmission charges levied by the IESO. The commodity cost of energy for certain low-volume and designated customers are based on the OEB's Regulated Price Plan (RPP), which consists of a two-tiered pricing structure with threshold amounts adjusted twice annually. Customers who are not eligible for the RPP pay the market price for electricity, adjusted for the difference between market prices and the prices paid to generators under the *Electricity Restructuring Act, 2004*. A summary of the RPP impacting the reporting period is provided below.

Summary of RPP

	Tier Threshold (kWh/month)		Tier Rates (cents/kWh)	
Effective Date	**Residential**	**Non-Residential**	**First Tier**	**Second Tier**
November 1, 2008	1,000	750	5.6	6.5
May 1, 2009	600	750	5.7	6.6
November 1, 2009	1,000	750	5.8	6.7

Purchased power costs decreased in 2010 by $11 million, or 2%, to $655 million compared to the same period last year. The decrease in our purchased power costs was primarily due to the impact of lower demand for electricity of $34 million, the impact of lower charges levied by the IESO of $4 million and lower costs associated with the OEB's RPP for residential and other eligible customers of $3 million compared to the same period last year. These decreases were partially offset by higher purchased power costs for customers who are not eligible for the RPP of $21 million and increased transmission charges due to the OEB's transmission rate decision effective July 1, 2009 and January 1, 2010 of $9 million in the first quarter compared to the same period last year.

Operation, Maintenance and Administration

Our operation, maintenance and administration costs consist of labour, material, equipment and purchased services which support the operation and maintenance of the transmission and distribution systems. Also included in these costs are property taxes and payments in lieu thereof on our transmission and distribution lines, stations and buildings.

Operation, maintenance and administration costs for each of our three business segments were as follows:

Three months ended March 31 (Canadian dollars in millions)	**2010**	**2009**	**$ Change**	**% Change**
Transmission	107	103	4	4
Distribution	137	127	10	8
Other	14	13	1	8
	258	243	15	6

Transmission

Operation, maintenance and administration expenditures incurred to sustain our high-voltage transmission stations, lines and rights-of-way increased by $4 million, or 4%, in the first quarter compared to the same period of the prior year. Within our work programs, we continued to invest in the safe and reliable operation of our transmission system that spans Ontario. Our work program expenditures were higher by $9 million. These increases were primarily attributable to higher expenditures on our planned station maintenance programs to support aging infrastructure, particularly on transformers, higher requirements for corrective station maintenance, engineering support and expanded forestry programs. Expenditures in support of the transmission system declined by $5 million reflecting the reallocation of resources to the capital work program, partially offset by higher information technology support expenditures and infrastructure enhancements.

Distribution

Operation, maintenance and administration expenditures incurred to sustain our low-voltage distribution system increased by $10 million, or 8%, in the first quarter compared to the same period of the prior year. Within our work programs, we experienced higher expenditures of $10 million primarily as a result of advancing our forestry programs to take advantage of weather conditions, and increased requirements for customer care and station maintenance programs. Our expenditures in support of our distribution system were consistent with the prior year.

Depreciation and Amortization

Depreciation and amortization expense for the first three months of the year increased by $15 million, or 12%, to $139 million relative to the comparative period. This increase was mainly attributable to new assets coming into service, consistent with our ongoing capital work program. In addition, amortization associated with the environmental regulatory asset was higher due to increased expenditures necessary to comply with Environment Canada regulations.

Financing Charges

Financing charges increased by $13 million, or 18%, to $85 million in the quarter compared to the same period last year. This increase was primarily due to a net increase in interest expense reflecting a higher average level of debt to support capital requirements partially offset by a lower average effective interest rate. In addition, the amount of capitalized interest was lower due to a significant reduction of the OEB-prescribed capitalization rate, partially offset by higher construction in progress levels.

Provision for Payments in Lieu of Corporate Income Taxes

The provision for payments in lieu of corporate income taxes decreased by $8 million, or 38%, to $13 million in the first quarter compared to the same period last year. This decrease results from lower pre-tax income this year and a reduction in the statutory rate from 33.0% to 31.0%. The net impact of temporary differences was minimal.

Net Income

Net income of $169 million was lower by $8 million, or 5%, compared to 2009 first quarter results. Net income was lower due to higher operating requirements primarily relating to our work program, and an increase in depreciation attributable to new assets coming into service. We also experienced higher financing charges reflecting the higher average level of debt to support capital expenditures, partially offset by lower average effective interest rates. The factors that resulted in lower net income were partially mitigated by higher revenues due primarily to the OEB-approved transmission tariff rate increases that were effective July 1, 2009 and January 1, 2010 which support investments in respect of the OPA's supply mix policy, including the phase-out of coal-fired generation and investments to address aging infrastructure. Our provision for payments in lieu of corporate income taxes was also lower due to a reduction in the statutory rate from 33.0% to 31.0%, as well as the impact of lower pre-tax income compared to prior year.

QUARTERLY RESULTS OF OPERATIONS

The following table sets forth unaudited quarterly information for each of the eight quarters from June 30, 2008 through March 31, 2010. This information has been derived from our unaudited interim Consolidated Financial Statements which, in the opinion of our management, have been prepared on a basis consistent with the audited annual Consolidated Financial Statements and which include all adjustments, consisting only of normal recurring adjustments, necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict our future performance.

(Canadian dollars in millions)	2010	2009					2008	
Quarter ended	Mar. 31	Dec. 31	Sep. 30	Jun. 30	Mar. 31	Dec. 31[2]	Sep. 30	Jun. 30
Total revenue[1]	1,319	1,207	1,144	1,090	1,303	1,194	1,126	1,055
Net income[1]	169	111	100	82	177	131	112	98
Net income to common shareholder[1]	165	106	96	77	173	126	108	93

[1] The demand for electricity generally follows normal weather-related variations, and therefore our electricity-related revenues and profit, all other things being equal, would tend to be higher in the first and third quarters than in the second and fourth quarters.

[2] As a result of the OEB's December 18, 2008 decision on Hydro One Networks' distribution rate application that was effective May 1, 2008, revenues in the fourth quarter of 2008 reflect a $25 million increase in respect of the period May 1, 2008 to December 31, 2008.

LIQUIDITY AND CAPITAL RESOURCES

Our primary sources of liquidity and capital resources are funds generated from operations, debt capital market borrowings and bank financing. These resources will be used to satisfy our capital resource requirements, which continue to include capital expenditures, servicing and repayment of our debt, payments related to our outsourcing arrangements, investing activities, and dividends.

Summary of Sources and Uses of Cash

Three months ended March 31 (Canadian dollars in millions)	2010	2009
Operating activities	287	181
Financing activities		
Long-term debt issued	1,000	600
Long-term debt retired	-	(400)
Short-term notes	(55)	150
Dividends paid	(14)	(108)
Investing activities		
Capital expenditures	(322)	(336)
Long-term investment	(250)	-
Other financing and investing activities	7	17
Net change in cash and cash equivalents	653	104

Operating Activities

Net cash from operating activities increased by $106 million, or 59%, to $287 million, compared to the same period last year. This change primarily reflects growth in accounts receivable balances throughout 2009 as a result of increased commodity costs and longer collection cycles associated with the economic downturn. Accounts receivable levels are beginning to stabilize and marginal declines in collection cycles have been experienced. The increase in cash from operating activities was also impacted by the changes to certain regulatory accounts, particularly the retail settlement variance account and the rural and remote rate protection variance account.

Financing Activities

Short-term liquidity is provided through funds from operations, our Commercial Paper Program, under which we are authorized to issue up to $1,000 million in short-term notes with a term to maturity of less than 365 days, additional bank lines and our holding of Province of Ontario Floating Rate Notes. At March 31, 2010, we had no short-term notes outstanding. The Commercial Paper Program is supported by a total of $1,500 million in liquidity facilities comprised of $1,250 million of committed revolving credit facilities with a syndicate of banks and the holding of $250 million of Province of Ontario Floating Rate Notes. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements.

During the quarter, we purchased $250 million Province of Ontario Floating Rate Notes maturing on November 19, 2014 as a form of alternate liquidity to supplement our bank credit facilities. We also reduced the existing revolving credit facility by $250 million to $750 million. Further, we entered into a new additional $500 million revolving credit facility with a syndicate of banks maturing February 2013. We plan to increase the amount of this new credit facility to $1,250 million and extend the term to June 2013. The increased new credit facility is in syndication and we currently have a commitment letter from a number of banks for $1,125 million of the $1,250 million. If and when this new credit facility is executed, the existing $750 million facility maturing in August 2010 will be cancelled.

At March 31, 2010, we had $7,875 million in long-term debt outstanding, including the current portion. Our notes and debentures mature between 2010 and 2046. Long-term financing is provided by our access to the debt markets, primarily through our Medium-Term Note (MTN) Program. On July 27, 2009, we filed a base shelf prospectus to renew our MTN Program for another 25 months. The maximum authorized principal amount of medium-term notes issuable under this program until August, 2011 is $3,000 million, of which $1,750 million was remaining and available as at March 31, 2010.

	Rating	
Rating Agency	**Short-term Debt**	**Long-term Debt**
DBRS Limited	R-1 (middle)	A (high)
Moody's Investors Service Inc.	Prime-1	Aa3
S&P	A-1	A+

We have the customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization, limit our ability to sell assets and impose a negative pledge provision, subject to customary exceptions. The credit agreements related to our credit facilities have no material adverse change clauses that could trigger default. However, the credit agreements require that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreements also provide limitations that debt cannot exceed 75% of total capitalization and that debt issued by our subsidiaries cannot exceed 10% of the total book value of our assets. We are in compliance with all these covenants and limitations as of March 31, 2010.

In the first quarter of 2010 we issued $1,000 million in long-term debt under our MTN Program. There were no debt maturities. In comparison, during the first quarter of 2009 we issued $600 million in long-term debt under our MTN Program and repaid $400 million in maturing long-term debt. In the first quarter of 2010, the amount of short-term notes outstanding decreased by $55 million compared to an increase of $150 million in the first quarter of 2009.

Common dividends are declared at the sole discretion of our Board of Directors, and are recommended by management based on results of operations, maintenance of the deemed regulatory capital structure, financial condition, cash requirements, and other relevant factors such as industry practice and shareholder expectations. Common dividends pertaining to the quarterly financial results are generally declared and paid in the immediately following quarter.

In the first quarter of 2010, we paid dividends to the Province in the amount of $14 million, consisting of $10 million in common dividends and $4 million in preferred dividends. In the comparative period for 2009, we paid common dividends of $104 million and preferred dividends of $4 million.

The Company's objectives with respect to its capital structure are to maintain effective access to capital on a long-term basis at reasonable rates, and to deliver appropriate financial returns. In order to ensure ongoing effective access to capital, the Company targets to maintain an "A" category long-term credit rating.

Investing Activities

Cash used for investing activities which primarily represents capital expenditures to enhance and reinforce our transmission and distribution infrastructure in the public interest, was as follows:

Three months ended March 31 (Canadian dollars in millions)	**2010**	**2009**	**$ Change**	**% Change**
Transmission	195	187	8	4
Distribution	126	148	(22)	(15)
Other	1	1	-	-
	322	336	(14)	(4)

Transmission

Transmission capital expenditures increased by $8 million, or 4%, in the first quarter to $195 million compared to the same period in 2009.

Expenditures to expand and reinforce our transmission system were $107 million, representing an increase of $20 million over last year. The increase is primarily attributable to inter-area network upgrade projects to support the OPA's supply mix objectives for generation. Expenditures incurred in the quarter also include continued investments in our local area supply projects to address growing loads.

The increase to inter-area network upgrade expenditures primarily relates to the Bruce to Milton Transmission Reinforcement Project, to connect refurbished nuclear and new wind generation sources in the Huron-Grey-Bruce area, and to the Northeast Transmission Reinforcement Project, which will increase the North-South Interface transfer capability to access available northern generation. In addition, we incurred expenditures associated with the commencement of the Static Var Compensator installations at Nanticoke and Detweiler Transformer Stations, which in the short-term will support increased

generation from the Bruce Nuclear facility and in the longer-term, will enhance the transfer capability between South Western Ontario and the Greater Toronto Area (GTA). These increases were partially offset by lower expenditures to the South Western Ontario Capacitor Banks Project, which provides interim protection to the Bruce Nuclear facility and which will expand transmission capacity in South Western Ontario, as well as lower expenditures to the Cherrywood Transformer Station to Claireville Transformer Station Connection Project, which will enable greater transfer capability across the GTA to accommodate power flows resulting from the new Hydro Québec interconnection, and is expected to be completed by the end of the year.

Local area supply projects with expenditures in the first quarter of 2010 include our GTA West Transmission Reinforcement Project, which was substantially completed in the period, and our Woodstock Area Transmission Reinforcement Project, both of which will increase capacity to ensure supply reliability in those areas, and our Hurontario Transformer Station to Jim Yarrow Municipal Transformer Station connection, also substantially completed in the period, and which will increase transmission capacity in the Western Brampton area to allow for future load growth. The final completion of our Niagara Reinforcement Project continues to be delayed by the aboriginal land dispute in the Caledonia area. Discussions related to the Niagara Reinforcement Project continue between the aboriginal peoples involved and various government entities and we expect to complete this project when site access becomes available.

Expenditures to sustain our existing transmission system were $72 million, representing an increase of $8 million compared to the same period in 2009. This increase is primarily related to higher targeted aging component replacements, specifically within our breaker installation and protection and control equipment programs. We also experienced higher expenditures related to the timing of wood pole replacements.

Our other transmission capital expenditures were $16 million in the first quarter of 2010, representing a reduction of $20 million from the same period in the prior year. The reduction from prior year was due to expenditures in 2009 on our investment in an entity-wide information system replacement and improvement project which replaced end-of-life systems and improved productivity, for which the second phase was completed during the third quarter of last year. In addition, expenditures incurred to enhance information security at our Ontario Grid Control Centre were lower compared to the same period in the prior year.

Distribution

Distribution capital expenditures decreased by $22 million, or 15%, to $126 million in the first quarter of 2010, compared to the same period of the prior year.

Capital expenditures to expand and reinforce our distribution network were $64 million, a reduction of $21 million compared to last year. This decrease is primarily due to the substantial completion of smart meter installations by the end of last year. Some smart meter installations continued in the current period as the total cumulative amount of installations nears the program's total target volume. Our ongoing investment in the Smart Meter Program is currently focused on the development and integration of the systems required for time-of-use billing, including meter reading capability and integration to the IESO meter data repository. We commenced the cut-over to time-of-use pricing for approximately 10,000 customers in the Municipality of Clarington within the quarter. With over 879,000 meters enabled for meter reading as at March 31, 2010, we will continue our efforts to migrate our customers to time-of-use pricing throughout the year. Our program is one of the largest smart meter deployments by a utility in North America.

Expenditures to sustain our distribution system were $57 million, an increase of $11 million from the same period in the prior year. This increase was primarily a result of higher expenditures on transportation and related work equipment and the planned replacement of end-of-life wood poles. In addition, we experienced higher expenditures related to line relocation work. These increases were partially offset by lower storm-recovery expenditures. Our other distribution capital expenditures were $5 million in 2010, representing a reduction of $12 million from last year. This reduction reflects our prior period investment in an entity-wide information system replacement and improvement project.

Future Capital Expenditures

Our capital expenditures for 2010 were originally budgeted at $2.0 billion. The 2010 capital budgets for our transmission and distribution businesses were approximately $1,150 million and $850 million, respectively. Capital expenditures were expected to increase to approximately $2.1 billion in 2011 and approximately $2.2 billion in 2012. These expenditures reflected the sustainment requirements of our aging infrastructure budgeted at approximately $530 million in 2010, $620 million in 2011 and $670 million in 2012. Development projects, including inter-area network upgrades that reflect the OPA's supply mix policies to phase out coal generation and local area supply requirements, were budgeted at approximately

$890 million in 2010, $780 million in 2011 and $550 million in 2012. These development investments also reflected the continued mass deployment of smart meters within our Distribution Businesses and the building of the required smart meter infrastructure in support of conservation objectives. We will leverage the smart meter investment to build a smart grid which will enhance our operations and support distributed generation. Other capital expenditures related to operations amounted to approximately $410 million in 2010, $290 million in 2011 and $230 million in 2012. Our capital expenditures to support the requirements under the Green Energy Act (GEA) were budgeted at approximately $190 million in 2010, $450 million in 2011 and $740 million in 2012. We are proceeding with our investments in support of the GEA to facilitate renewable generation consistent with the Feed-in-Tariff program. Capital expenditures of our other business segment were budgeted at about $15 million in 2010, primarily reflecting the continued build out of the fibre optic network.

As a result of factors such as ongoing discussions with the OPA regarding transmission project needs and priorities and distributed generation requirements, as well as the OEB's distribution rate decision issued April 9, 2010, capital expenditures for 2010 are expected to be lower by approximately $400 million. Budgets for 2011 and 2012 are currently anticipated to be lower by approximately $100 million and $250 million, respectively. Many projects require external approvals or may be subject to other external influences outside of our control.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of our debt and other major contractual obligations as well as other major commercial commitments.

March 31, 2010 (Canadian dollars in millions)	**Total**	**2010**[1]	**2011/2012**	**2013/2014**	**After 2014**
Contractual Obligations *(due by year)*					
Long-term debt – principal repayments	7,875	600	1,100	1,350	4,825
Long-term debt – interest payments	6,463	351	748	628	4,736
Inergi LP (Inergi) outsourcing agreement[2]	196	78	118	-	-
Operating lease commitments	57	7	12	12	26
Environmental obligations[3]	386	21	68	79	218
Total Contractual Obligations	14,977	1,057	2,046	2,069	9,805
Other Commercial Commitments *(by year of expiry)*					
Bank line[4]	1,250	750	-	500	-
Letters of credit[5]	107	107	-	-	-
Guarantees[5]	326	326	-	-	-
Pension[6]	321	80	231	10	-
Total Other Commercial Commitments	2,004	1,263	231	510	-

[1] The amounts disclosed represent the balances due over the period April 1, 2010 to December 31, 2010.

[2] On April 30, 2010, the Company exercised its option under its current Master Services Agreement (MSA) with Inergi to renew for a further three-year period. The term of the current agreement, which expires on February 29, 2012, has been extended to February 28, 2015. Under the extended agreement, Inergi will provide business processing and information technology outsourcing services, as well as core system support related primarily to SAP implementation and optimization. Over the next five years of the MSA, total payments to Inergi for services will be about $650 million.

[3] The Company records a liability for the estimated future expenditures associated with the phase-out and destruction of PCB-contaminated insulating oil from electrical equipment and for the assessment and remediation of contaminated lands. The expenditure pattern reflects our planned work program for the period.

[4] As a backstop to our commercial paper program, we have a $750 million revolving standby credit facility with a syndicate of banks which matures in August 2010 and a new additional $500 million facility with a syndicate of banks which matures in February 2013. We plan to increase the amount of this new credit facility to $1,250 million and extend the term to June 2013. The increased new credit facility is in syndication and we currently have a commitment letter from a number of banks for $1,125 million of the $1,250 million. If and when this new credit facility is executed, the existing $750 million facility maturing in August 2010 will be cancelled..

[5] We currently have bank letters of credit of $107 million outstanding relating to retirement compensation arrangements. We have also provided prudential support to the IESO on behalf of our subsidiaries as required by the IESO's Market Rules, using parental guarantees of up to a maximum of $325 million and on behalf of two distributors using guarantees of up to a maximum of $660 thousand. Although no letters of credit are required for prudential support, we would have to resume providing bank letters of credit if our credit rating deteriorated to below the "Aa" category.

[6] Contributions to the pension fund are made one month in arrears. Contributions continue to be based on the actuarial valuation effective December 31, 2006; however, the actual contribution for this year and beyond will be rebased from the actuarial valuation effective December 31, 2009, filed later this year, and will depend on investment returns, changes in benefits or actuarial assumptions.

The amounts in the above table under long-term debt – principal repayments, are not charged to our results of operations, but are reflected on our Balance Sheet and Statement of Cash Flows. Interest associated with this debt is recorded under financing charges on our Statement of Operations or in our capital programs. Payments in respect of operating leases and our outsourcing agreement with Inergi are recorded under operation, maintenance and administration costs on our Statement of Operations or within our capital expenditures.

RELATED PARTY TRANSACTIONS

Related party transactions primarily consist of our transmission revenues received from, and our power purchases payments made to, the IESO, which is a related party by virtue of its status as an agency of our shareholder, the Province. The year-over-year changes related to these amounts are described more fully in our discussion of our transmission revenues and purchased power costs. Other significant related party transactions include our dividends which are paid to the Province and our payments in lieu of corporate income taxes which are paid or payable to the Ontario Electricity Financial Corporation. In January 2010, the Company purchased $250 million Province of Ontario Floating Rate Notes maturing on November 19, 2014 as a form of alternate liquidity to supplement its bank credit facilities.

CONSIDERATIONS OF CURRENT ECONOMIC CONDITIONS

Pension

During the first three months of 2010, the deferred pension asset reported on our balance sheet decreased by $15 million to $409 million. We contributed $30 million into our pension plan in 2010 and incurred $45 million in net periodic pension benefit cost. This contribution was based on the actuarial valuation effective December 31, 2006; however, the actual contribution for the year will be rebased from the actuarial valuation effective December 31, 2009, filed later this year, and will depend on investment returns, changes in benefits and actuarial assumptions.

Our pension plan experienced a positive return of 2% in the first quarter of this year. Consistent with other pension plans, our pension plan could be negatively impacted during the remainder of the year as a result of the current economic uncertainty and financial market volatility. However, our fund continues to recover and experience positive returns since it was negatively impacted in 2008 and into the first quarter of 2009. The overall return for 2009 was positive.

The pension fund has broad exposure from its investments in domestic and international equity markets, as well as in fixed income markets. The overall exposure of the fund reflects its holdings across a number of sectors, and a well-diversified portfolio to support long-term objectives.

We continue to monitor our financial risks, including credit risk.

STATUS OF OUR TRANSITION TO INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

On February 13, 2008, the Canadian Accounting Standards Board confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian generally accepted accounting principles (GAAP) for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011, with comparative data also reported under IFRS. In anticipation of this decision, we commenced our IFRS conversion project in 2007.

The project has four separate phases: diagnostic, design and planning, solution development, and implementation. We completed the diagnostic phase in 2008. It involved a high level review and identification of the major differences between current GAAP and IFRS in all subject areas resulting in the identification of the areas of accounting difference with the highest potential to significantly impact our company.

In 2009, we completed the design and planning and the solution development phases of our project, including substantial completion of all our policy analyses. We are currently engaged in the implementation phase which is the final phase of our project. We are currently tracking our 2010 results under IFRS, assuming that the recognition of regulatory assets and liabilities will be permitted, in anticipation of having 2010 comparative numbers ready for reporting under IFRS in the first quarter of 2011. We are concurrently developing plans to support accounting and business processes should rate-regulated accounting be discontinued. Our teams continue to monitor progress relative to key milestones, monitor developments of the International Accounting Standards Board (IASB or the Board), update recommendations and develop financial reports. We

continue to have recurring dialogue with our external auditors about possible outcomes of our project. We continue to evaluate the impacts of current and prospective IFRS on all of our business activities, including those of our subsidiaries and the impact on our entity-wide information system. We are simultaneously analyzing the impacts of changes on our disclosure controls and internal controls over financial reporting, our debt covenants and our performance measures. We continue to provide formal communications to our employees. We have completed numerous staff training sessions and will plan for future training sessions as standards continue to evolve.

Accounting Policies

During 2009, both the Public Sector Accounting Board (PSAB) and the Canadian Securities Administrators' staff confirmed that companies such as Hydro One will be required to adopt IFRS in 2011. On December 14, 2009, the PSAB issued an exposure draft proposing to remove the requirement for government organizations adhering to IFRS to also apply additional public sector financial reporting standards, currently Public Sector Accounting Handbook Section 3270. The effective date for the proposed changes is January 1, 2011.

The areas with the highest potential to significantly impact our company, identified during the diagnostic phase, are regulatory assets and liabilities, fixed assets, payments in lieu of corporate income taxes, employee future benefits, as well as initial adoption of IFRS under the provisions of IFRS 1, *First-Time Adoption of IFRS* (IFRS 1). The IASB's project on rate-regulated activities (RRA) will have an impact on the accounting choices available in all of these areas.

In December 2008, the IASB added a project on RRA to its agenda. In July 2009, the IASB issued an exposure draft detailing its proposals for standards for the accounting of RRA. The exposure draft allows for the continued recognition of regulatory assets and liabilities on the Balance Sheet. In-scope assets and liabilities are proposed to be carried at the net present value of the expected future cash flows. The exposure draft makes an exception to the requirements of other IFRS standards by allowing capitalization of otherwise ineligible costs within fixed assets and intangible assets on the basis of the inclusion of these costs in rate base. The IASB requested comments from interested observers on the exposure draft. We responded to the IASB's request for comment on November 24, 2009. The IASB received approximately 150 responses to its request for comment, which were very diverse in their opinions. As a result, the IASB staff postponed presenting their analysis of the responses to the IASB, originally scheduled for January, to the Board's February meeting. The presentation to the IASB in February included options for the next steps of the project.

The Board decided tentatively to finalize the transition relief for first-time adopters. The transition relief proposed offers an optional exemption for a first-time adopter with RRA to use the carrying amount of fixed assets or intangible assets as deemed cost on the transition date when the carrying amount includes costs that would note otherwise qualify for capitalization. On May 6, 2010, the IASB issued the omnibus *Improvements to IFRSs*, which included the expected amendment to IFRS 1 applicable to entities with RRA. We expect to elect this exemption for our regulated businesses.

In terms of specific aspects of the project, the Board directed the IASB staff to continue its research and analysis and to focus on the key issue of whether regulatory assets and liabilities exist in accordance with the current IFRS framework and whether they are consistent with other standards. The Board will continue deliberations and plans to present a new schedule later this year. It is unclear at this time what the outcome of the IASB's deliberations will be and how reporting standards will be impacted. It is possible that the outcome may result in a discontinuance of regulatory accounting, in which case the Company would be required to write-off its regulatory assets and liabilities. This discontinuance would result in a write-off of regulatory assets and regulatory liabilities for a net reduction to retained earnings of approximately $339 million as at December 31, 2009.

In-Progress Construction and Development

Under current IFRS, there is a significant difference to Canadian GAAP in terms of what costs can be capitalized to in-progress construction and development projects. The impact of this difference on our financial statements cannot reasonably be estimated until greater clarity is provided by the IASB on the future direction of its RRA project.

Employee Future Benefits

Given that the RRA project has not been finalized at this point, it is unclear at this time whether the continuation of accounting for expenditures related to employer sponsored pension plans on a cash basis would be permissible. Regulatory assets and liabilities, representing the cumulative difference between our company's pension contributions accounted for on a cash basis at the direction of the regulator, and the costs that would be recognized on an accrual basis under Canadian GAAP,

may not meet the definition of assets or liabilities under IFRS and hence may require de-recognition as at the IFRS transition date. Similarly, we are assessing our options with respect to the recognition of accumulated, unamortized actuarial gains and losses associated with employment benefits. Currently, the possible alternatives to account for these pension and other employee benefit amounts include charging unamortized actuarial gains and losses immediately upon adoption under IFRS 1 or recognizing an adjustment to those amounts retrospectively to comply with IAS 19, *Employee Benefits*. Our policy choice may be contingent upon the outcome of the RRA project. The impact of using IFRS 1 as at December 31, 2009 would be a change to retained earnings of $852 million.

Payments in Lieu of Corporate Income Taxes

We recognize future tax assets and liabilities in accordance with CICA HB section 3465, *Income Taxes*, which was amended effective January 1, 2009 to bridge the convergence to IFRS. As such, we have determined that there is no potential for a significant impact for this class of transactions based upon contingent outcomes regarding transactions for payments in lieu of corporate income taxes. If the RRA project is adopted as is, we plan to continue to record taxes on a cash basis instead of the liability method for the regulated businesses. Currently, we expect to record differences in items credited or charged directly to equity, financial instruments and unused tax losses and unused tax credits. If rate-regulated accounting is not permitted, the impact on our provision for payments in lieu of corporate income taxes would be recognized using the liability method and there would be no regulatory accounts established for taxes to be recovered through future rates. As a result the provision for PILs as at December 31, 2009 would have been lower by approximately $46 million including the impact of a change in substantively enacted tax rates.

OEB Consultation

In May 2008, the OEB initiated a consultative process to determine the nature of any changes to regulatory reporting requirements in response to IFRS. The OEB held public meetings and a formal stakeholder conference in May 2009. We participated at each opportunity offered to the public to communicate with the OEB. On July 28, 2009, the OEB released some preliminary views on how regulatory reporting requirements will change in response to IFRS. The OEB has initiated a second phase of its consultative process to amend certain regulatory instruments. We are continuing to assess the impact of the OEB's report and other recommendations on our IFRS conversion project.

On February 24, 2010, the OEB issued a letter to all licensed electricity distributors and rate-regulated natural gas utilities for the purpose of clarifying the OEB's view released in July on accounting for overhead costs in the cost of new capital works effective January 1, 2011. The OEB stated in the letter that it would be requiring full compliance with IFRS requirements, including those in IAS 16, *Property, Plant and Equipment* (IAS 16), as applicable to non-regulated enterprises and only where the OEB authorizes specific alternative treatment for regulatory purposes is alternative treatment acceptable. We continue to assess this guidance in light of our rate applications.

Internal Control over Financial Reporting and Disclosure Controls and Procedures

We are continuously analyzing the impacts of changes on our disclosure controls and procedures and internal controls over financial reporting as we proceed through our implementation of IFRS. Additional disclosure controls may be required to address first time adoption and additional internal controls may be required to implement changes in our accounting policies and our ongoing IFRS reporting requirements. Required changes to our control environment cannot be determined until such time as policy choices are finalized.

We have initiated the process of analyzing our current disclosure control and procedure and internal control documentation to identify changes required upon the adoption of IFRS. We have categorized each control process as low, medium or high impact, based on the currently assessed risk of a major change being required upon implementation of IFRS in 2011. This ranking was completed in the fourth quarter of 2009. We are currently updating the documentation for all of the low and medium risk processes with IFRS implementation impact, including process documentation and risk and control matrices, with an estimated completion by the end of the second quarter of 2010. For our high risk processes we anticipate completing our documentation revisions by the end of the third quarter of 2010, subject to any decision made by the IASB on the RRA project. Process revisions on high risk areas are being completed last due to the potential for impacts as a result of the RRA project. Walkthroughs of the revised process and control documentation is expected to be completed in the third quarter for low and medium-risk processes and in the fourth quarter of 2010 for high-risk processes, subject to any decision by the IASB on the RRA project.

Financial Reporting Expertise

The project's formal governance structure includes a steering committee consisting of senior level management from finance, information technology, treasury and our operations organizations. Project status reporting is provided to senior executive management and to the Audit and Finance Committee of our Board of Directors on a quarterly basis, or more often as necessary.

The training of key finance and operational staff commenced in 2007 and has been on-going. Training has also been given to the Audit and Finance Committee and senior executive management to communicate the key differences between Canadian GAAP and IFRS, and to provide them with an overview of the key impacts conversion could have on our financial statements. These groups are updated as developments in IFRS continue. Due to the extensive staffing requirements associated with such a large-scale project, an external expert advisor was engaged to assist with our IFRS conversion project, from the planning phase through to implementation.

Business Activities

The company has the customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization. Depending on the outcome of various exposure drafts under IFRS, we could undergo changes to our results that would impact our debt covenants. For example, covenants would be impacted as a result of de-recognition of regulatory assets and liabilities, accounting for expenditures related to employer sponsored pension plans on an accrual basis versus a cash basis and the change in costs that are allowable versus disallowable for capitalization as part of the cost of self-constructed assets. As part of our IFRS transition project, we have been analyzing the impacts of potential changes in accounting policy on our debt covenant and communicating potential scenarios and impacts analyses to our Audit and Finance Committee. Based on our calculations, we would remain in compliance with our debt covenants. However, we have met with our financial institutions and amended our credit agreement to consider the potential impacts that IFRS may have on our covenants. Specifically, the calculation of our debt to total capitalization ratio will be modified for certain items to factor IFRS impacts, such that the debt to total capitalization is representative of what it was prior to IFRS. We will continue to monitor the impact of conversion on our debt covenants as IFRS develops and as we finalize our policy choices under IFRS.

Information Technology (IT) Systems

As part of an entity-wide system improvement project, many of our major financial systems were replaced in 2008 and 2009. To ensure that the future requirements of IFRS would be met, common team members were included within the governance structure of our IFRS project and the new entity-wide system implementation team. At the same time, members of the IFRS implementation team were involved in the design of our new entity-wide system. IT implications were identified and assessed during our diagnostic and design and planning stages of our IFRS project and were incorporated in the project's solution development stage. For example, the new system has been configured to track depreciation on a component level, based on the useful life of the asset, as currently required under IAS 16. The new system has also been configured to track allowable versus disallowable costs for capitalization under IAS 16. The system has been designed with the maximum flexibility given the uncertainty of rate-regulated accounting under the IASB's current project. The degree of future required re-configurations will depend on the outcome of the RRA project.

DISCLOSURE CONTROLS AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

In 2008, we began transitioning our major financial systems to a SAP enterprise-wide platform as part of the entity-wide information system replacement and improvement project. A formal project governance structure is in place to ensure an effective transition of the information technology systems and business processes. The governance structure includes a steering committee consisting of senior levels of management which reports to senior executive management and the Business Transformation Committee of the Board of Directors.

In 2008, we successfully implemented the first phase of the supply chain, asset and work management modules in SAP. In 2009, we successfully implemented various Finance, Human Resources, Payroll and Investment Management modules. The reporting tool Business Intelligence/Business Warehouse (BI/BW) was also implemented. This implementation included new controls over Internal Controls over Financial Reporting and the replacement of other controls in the previous environment. Our process documentation has been updated and the design and effectiveness of the controls have been tested.

In compliance with the requirements of National Instrument 52-109, *Certification of Disclosure in Issuers' Annual and Interim Filings*, our Certifying Officers have reviewed and certified the Consolidated Financial Statements for the interim period ended March 31, 2010, together with other financial information included in our quarterly securities filings. Our Certifying Officers have certified that disclosure controls and procedures have been designed to provide reasonable assurance that material information relating to our company is made known within our company. Further, our Certifying Officers have also certified that internal controls over financial reporting have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements.

RECENT DEVELOPMENTS

Debt issues

On March 15, 2010, we issued $300 million of notes at a coupon rate of 4.40% and with a maturity date of June 1, 2020. On the same date, we issued an additional offering of $200 million of notes at a coupon rate of 5.49% maturing on July 16, 2040, originally issued on July 16, 2009. The total amount outstanding for that issue is now $500 million. In the first quarter, we successfully issued a total of $1,000 million of cost-effective debt financing.

Status of Rate Applications

On December 11, 2009, the OEB issued its final report on the cost of capital review which concluded that the formula-based return on equity (ROE) needed to be reset and refined. On January 5, 2010, we filed a motion with the OEB to review aspects of its decision on our 2010 transmission rates including an increase of the ROE used in calculating the 2010 revenue requirement to 9.75% from 8.39% based on the new OEB-approved formula. On April 5, 2010, the OEB issued its decision denying Hydro One Network's motion to vary the ROE used to calculate the revenue requirement for 2010 transmission rates. As a result of the decision, the revenue requirement will remain at $1,257 million on the basis of an ROE of 8.39%.

We intend to file our transmission revenue requirement and rate application for the years 2011-2012 in May 2010 which will incorporate, among other things, those items essential to the safe and reliable operation of our existing assets, projects already under development and approved by the OEB and projects critical to the connection of renewable generation that have been identified by the OPA as part of the Province's green energy agenda.

On April 9, 2010, the OEB released its decision regarding the 2010-2011 rate application made by our subsidiary Hydro One Networks in respect of its Distribution Business. The revised rates were approved for implementation on May 1, 2010 and January 1, 2011, respectively. On April 16, 2010, Hydro One Networks filed a draft rate order proposing revenue requirements of $1,146 million for 2010 and $1,236 million for 2011 which are expected to reflect rate increases of approximately 9.3% in 2010 and 10.5% in 2011 in support of necessary work programs, the implementation of the Green Energy Act and the installation of smart meters. The total impact on an average customer's total bill is expected to be approximately 3% and 3.5% for 2010 and 2011, respectively. The 2010 and 2011 revenue requirements were lower than the requested $1,150 and $1,264 million adjusted for reductions in operation, maintenance and administration expenses, capital expenditures and working capital requirements. On April 29, 2010, the OEB issued the final rate order for the 2010 distribution rates, which was consistent with the draft order filed on April 16, 2010. The 2011 rates will be finalized following the *Consensus Forecast* in September, 2010, when the 2011 return on equity will be forecasted.

On April 13, 2010, the OEB released its decision regarding the 2010 rate application made by our subsidiary, Hydro One Brampton Networks Inc. The OEB approved our submission on the basis of the OEB's cost of capital and second generation IRM policies. The revised rates have an implementation date of May 1, 2010 and will result in a reduction of approximately 8.3%, or 2.2% on an average customer's total bill in the year.

On April 14, 2010, the OEB issued a decision regarding the 2010 rate application for our subsidiary, Hydro One Remote Communities Inc. under the OEB's third generation IRM policies. The revised rates were approved for implementation on May 1, 2010 and reflect an increase of approximately 0.4%, for which the overall impact on an average customer's total bill would be marginal.

Conservation and Demand Management (CDM) Targets

On April 26, 2010, the Minister of Energy and Infrastructure issued a Minister's Directive to the OEB to take steps to establish electricity CDM targets for Ontario's local distribution companies (LDCs). The two key CDM targets for LDCs over the four years beginning January 1, 2011 will be the shaving of 1,330 MW of provincial peak demand and 6,000 gigawatt hours of accumulated reduced electricity consumption, collectively. The OPA was directed to advise the OEB on the appropriate allocation of the CDM targets between the LDCs.

Forward Rate Agreements

On April 26, 2010, we entered into four forward rate agreements in order to lock-in four interest rate resets on the floating rate we pay on $500 million of floating rate debt. The four forward rate agreements are classified as held-for-trading and measured at fair value.

SELECTED FINANCIAL HIGHLIGHTS AND RATIOS

Three months ended March 31 (Canadian dollars in millions, except earnings per common share)	**2010**	**2009**
Net income	169	177
Net cash from operating activities	287	181
Capital expenditures	322	336
Earnings per common share	1.651	1.724
Earnings coverage ratio[1]	2.08	2.53
Net asset coverage on long-term debt[2]	1.71	1.79
Total debt to capitalization[3]	59%	56%

[1]The earnings coverage ratio has been presented for the twelve months ended March 31, 2010 and March 31, 2009, respectively and has been calculated as the sum of net income, provision for payments in lieu of corporate income taxes and financing charges divided by the sum of financing charges, capitalized interest and cumulative preferred dividends.

[2]The net asset coverage on long-term debt ratio has been presented as at March 31, 2010 and December 31, 2009 and has been calculated as total assets minus total liabilities excluding long-term debt (including current portion) divided by long-term debt (including current portion).

[3]Total debt to capitalization ratio has been presented as at March 31, 2010 and December 31, 2009 and has been calculated as total debt divided by total debt plus total shareholder's equity.

FORWARD-LOOKING STATEMENTS AND INFORMATION

Our oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate and include beliefs and assumptions made by the management of our company. Such statements include, but are not limited to: expectations regarding energy related revenues and profit; expectations regarding developments in the statutory and operating framework for electricity distribution and transmission in Ontario including amendments to codes, the impact of new regulatory guidelines and impacts of decisions from the OEB and other governing bodies; statements related to the status of our rate applications and rate changes including expected impacts on an average customer's bill and expectations regarding our transmission revenue requirement and rate application for the years 2011-2012; expectations regarding rate increases; statements regarding our future liquidity and capital resource requirements; expectations regarding our financing activities including statements related to increasing our new credit facility; expectations regarding the results of our on-going and planned projects and/or initiatives and their completion dates; statements regarding future capital expenditures, budgets and our investment plans; statements related to smart meters and the associated smart grid; statements regarding contractual obligations and other commercial commitments; statements about our outsourcing arrangement with Inergi LP; statements regarding the amount and timing of future estimated environmental expenditures; statements regarding future pension contributions and our pension plan; statements about IFRS, IASB, our conversion to IFRS, planned courses of action, and expected impacts in the event of a discontinuance of regulatory accounting; statements related to our debt covenants; and statements regarding CDM targets. Words such as "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", "goal", "aim", "target", and "continue", and variations of such words and similar expressions, are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. We do not intend, and we disclaim any obligation to update any forward-looking statements, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; no unfavourable decisions from the OEB and other regulatory bodies concerning outstanding rate and other applications; no unforeseen changes in rate orders or rate structures for our distribution and transmission businesses; a stable regulatory environment; the preparation of business plans, regulatory filings and future capital expenditures on the basis that commencing in 2011 rate regulated accounting will continue to exist under IFRS; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to us, including information obtained from third party industry analysts. Actual results may differ materially from those predicted by such forward-looking statements. While we do not know what impact any of these differences may have, our business, results of operations, financial condition and our credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- the risks associated with being controlled by the Province;
- the impact of the final outcome of the exposure draft on rate regulated accounting;
- on-going discussions with the OPA regarding transmission project needs and priorities and distributed generation requirements;
- any opposition to and delays or denials of the requisite approvals and accommodations for our planned projects;
- the result of regulatory decisions regarding our revenue requirements, cost recovery and rates;
- investment returns, changes in benefits or actuarial assumptions;
- the risk that previously granted regulatory approvals may be subsequently challenged, appealed or overturned;
- the risks associated with changes in interest rates;
- the risks associated with current economic uncertainty and financial market volatility; and
- the impact of the GEA on our company and the costs and expenses arising there from.

We caution the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail under "Risk Management and Risk Factors" in the 2009 annual Management's Discussion and Analysis (MD&A). You should review the section entitled "Risk Management and Risk Factors" in detail.

This MD&A is dated as at May 13, 2010. Additional information about our company, including our Annual Information Form, is available on SEDAR at www.sedar.com.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (unaudited)

Three months ended March 31 (Canadian dollars in millions, except per share amounts)	2010	2009
Revenues		
Transmission	320	302
Distribution	983	986
Other	16	15
	1,319	1,303
Costs		
Purchased power	655	666
Operation, maintenance and administration	258	243
Depreciation and amortization	139	124
	1,052	1,033
Income before financing charges and provision for payments in lieu of corporate income taxes	267	270
Financing charges	85	72
Income before provision for payments in lieu of corporate income taxes	182	198
Provision for payments in lieu of corporate income taxes	13	21
Net income	169	177
Other comprehensive loss	-	-
Comprehensive income	169	177
Basic and fully diluted earnings per common share *(Canadian dollars)*	1.651	1.724

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS (unaudited)

Three months ended March 31 (Canadian dollars in millions)	2010	2009
Retained earnings, beginning of period	1,791	1,497
Change in accounting policy for the recognition of future income tax assets and liabilities *(Note 2)*	-	12
Net income	169	177
Dividends *(Note 3)*	(14)	(108)
Retained earnings, end of period	1,946	1,578

CONSOLIDATED STATEMENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME (unaudited)

Three months ended March 31 (Canadian dollars in millions)	2010	2009
Accumulated other comprehensive income, beginning of period	(10)	(10)
Other comprehensive loss	-	-
Accumulated other comprehensive income, end of period	(10)	(10)

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (unaudited)

(Canadian dollars in millions)	March 31, 2010	December 31, 2009
Assets		
Current assets:		
Short-term investments	647	-
Accounts receivable (net of allowance for doubtful accounts)	851	843
Regulatory assets	71	72
Materials and supplies	22	21
Future income tax assets	23	21
Other	11	16
	1,625	973
Fixed assets:		
Fixed assets in service	18,617	18,407
Less: accumulated depreciation	6,926	6,815
	11,691	11,592
Construction in progress	1,359	1,256
Future use land, components and spares	149	150
	13,199	12,998
Other long-term assets:		
Regulatory assets	1,081	1,033
Deferred pension asset	409	424
Intangibles (net of accumulated amortization)	213	218
Goodwill	133	133
Future income tax assets	17	18
Other assets	12	13
Long-term investment *(Note 4)*	249	-
	2,114	1,839
Total assets	16,938	15,810

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (unaudited) (continued)

(Canadian dollars in millions)	March 31, 2010	December 31, 2009
Liabilities		
Current liabilities:		
Bank indebtedness	20	26
Accounts payable and accrued charges	735	800
Regulatory liabilities	108	100
Accrued interest	123	74
Short-term notes payable	-	55
Long-term debt payable within one year *(Note 5)*	850	600
	1,836	1,655
Long-term debt *(Note 5)*	7,032	6,281
Other long-term liabilities:		
Employee future benefits other than pension	950	940
Regulatory liabilities	478	504
Future income tax liabilities	754	693
Environmental liabilities	299	303
Long-term accounts payable and other liabilities	16	16
	2,497	2,456
Total liabilities	11,365	10,392
Shareholder's equity		
Preferred shares (authorized: unlimited; issued: 12,920,000)	323	323
Common shares (authorized: unlimited; issued: 100,000)	3,314	3,314
Retained earnings	1,946	1,791
Accumulated other comprehensive income	(10)	(10)
Total shareholder's equity	5,573	5,418
Total liabilities and shareholder's equity	16,938	15,810

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

Three months ended March 31 (Canadian dollars in millions)	2010	2009
Operating activities		
Net income	169	177
Environmental expenditures	(3)	(1)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	128	115
Regulatory liability refund account	(8)	(5)
Smart meters	(7)	(3)
Rural and remote rate protection variance account	7	(2)
Retail settlement variance accounts	5	(7)
Other regulatory asset and liability accounts	-	1
Future income taxes	9	3
	300	278
Changes in non-cash balances related to operations	(13)	(97)
Net cash from operating activities	287	181
Financing activities		
Long-term debt issued	1,000	600
Long-term debt retired	-	(400)
Short-term notes payable	(55)	150
Dividends paid	(14)	(108)
Other	-	5
Net cash from financing activities	931	247
Investing activities		
Capital expenditures		
Fixed assets	(317)	(311)
Intangible assets	(5)	(25)
	(322)	(336)
Long-term investment	(250)	-
Other assets	7	12
Net cash used in investing activities	(565)	(324)
Net change in cash and cash equivalents	653	104
Cash and cash equivalents, beginning of period *(Note 7)*	(26)	16
Cash and cash equivalents, end of period	627	120

See accompanying notes to Consolidated Financial Statements.

1. BASIS OF PRESENTATION

These interim Consolidated Financial Statements do not conform in all respects to the disclosure requirements of Canadian generally accepted accounting principles for annual financial statements and should, therefore, be read in conjunction with the annual Consolidated Financial Statements of Hydro One Inc. (Hydro One or the Company) for the year ending December 31, 2009 which include information necessary or useful to understanding the Company's business and financial statement presentation. In particular, the Company's significant accounting policies and practices are presented as Note 2 to the annual Consolidated Financial Statements, and have been consistently applied in the preparation of these interim Consolidated Financial Statements.

The demand for electricity generally follows normal weather-related variations, and therefore the Company's energy-related revenues, all other things being equal, will tend to be higher in the first and third quarters than in the second and fourth quarters.

2. ACCOUNTING CHANGES

Change in Accounting Policy – Income Taxes

Effective January 1, 2009, the Company adopted amendments to the CICA Handbook Section 3465 - *Income Taxes* and CICA Handbook Section 1100 - *Generally Accepted Accounting Standards*. These amended sections establish new standards for the recognition, measurement, presentation and disclosure of future income tax assets and liabilities of rate-regulated enterprises.

For transactions and events that cause temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, the adoption of these amended sections requires the recognition of future income tax assets and liabilities, and correspondingly the recognition of regulatory liabilities and assets. The temporary differences primarily relate to capital cost allowance in excess of deprecation and employee future benefits other than pension.

As a result of adopting these amended standards, on January 1, 2009, the Company recognized current future income tax assets of $20 million, long-term future income tax assets of $12 million and long-term future income tax liabilities of $503 million. The Company also recognized corresponding current regulatory liabilities of $29 million, long-term regulatory liabilities of $14 million and long-term regulatory assets of $526 million. An adjustment to retained earnings of $12 million was recorded as at January 1, 2009 for the cumulative earnings impact of future income tax assets and liabilities as at December 31, 2008 that are excluded from the rate-setting process.

3. DIVIDENDS

During the three months ended March 31, 2010, preferred dividends in the amount of $4 million (2009 - $4 million) and common dividends in the amount of $10 million (2009 - $104 million) were declared.

4. LONG-TERM INVESTMENT

On January 22, 2010, Hydro One purchased $250 million Province of Ontario Floating Rate Notes maturing on November 19, 2014 as a form of alternate liquidity to supplement its bank credit facilities. The Company has classified this investment as held-for-trading and therefore it has been recorded at fair value on the Consolidated Balance Sheet.

5. LONG-TERM DEBT

During the three months ended March 31, 2010, Hydro One issued additional notes under the Company's Medium-Term Note Program.

The first issue on January 22, 2010 was an additional offering of 3.13% notes with a principal amount of $500 million. The notes mature on November 19, 2014 and were originally issued on November 19, 2009 for $250 million, bringing the total amount outstanding for this issue to $750 million.

The second issue on March 15, 2010 was an offering of 4.40% notes with a principal amount of $300 million. The notes mature on June 1, 2020.

The third issue on March 15, 2010 was an additional offering of 5.49% notes with a principal amount of $200 million. The notes mature on July 16, 2040 and were originally issued on July 16, 2009 for $300 million, bringing the total amount outstanding for this issue to $500 million.

On January 22, 2010, Hydro One entered into two $250 million notional principal amount fixed-to-floating interest rate swaps to convert $500 million of Hydro One's 3.13% coupon note maturing November 19, 2014, into three-month variable rate debt. The Company designated these as fair value hedges associated with interest rate risk with the changes in fair value recognized in the Consolidated Statement of Operations for the period, along with changes in the fair value of the fixed rate note that is attributable to the hedged risk. To the extent the hedge is ineffective, the ineffective amount is recognized immediately to financing charges in the Consolidated Statement of Operations, and this amount was insignificant for the period.

6. EMPLOYEE FUTURE BENEFITS

Total benefit costs are as follows:

Three months ended March 31 (Canadian dollars in millions)	2010	2009
Pension		
Net periodic benefit cost	45	32
Pension fund contribution	30	29
Less: Portion attributable to labour and capitalized as part of the cost of fixed assets	12	12
Charged to results of operations	18	17
Employee Future Benefits Other than Pension		
Net periodic benefit cost	22	20
Less: Portion attributable to labour and capitalized as part of the cost of fixed assets	9	8
Charged to results of operations	13	12

7. CONSOLIDATED STATEMENTS OF CASH FLOWS

For the purposes of the Consolidated Statements of Cash Flows, "cash and cash equivalents" refers to the Consolidated Balance Sheet items "short-term investments" and "bank indebtedness."

8. SEGMENTED REPORTING

Hydro One has three reportable segments:

- The Transmission Business, which comprises the core business of providing transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
- The Distribution Business, which comprises the core business of delivering and selling electricity to customers; and
- An "other" segment primarily consisting of a telecommunications business.

The designation of segments has been based on a combination of regulatory status and the nature of the products and services provided. Segment information on the above basis is as follows:

Three months ended March 31 (Canadian dollars in millions)	Transmission	Distribution	Other	Consolidated
2010				
Segment profit				
Revenues	320	983	16	1,319
Purchased power	-	655	-	655
Operation, maintenance and administration	107	137	14	258
Depreciation and amortization	64	73	2	139
Income before financing charges and provision for payments in lieu of corporate income taxes	149	118	-	267
Financing charges				85
Income before provision for payments in lieu of corporate income taxes				182
Capital expenditures	195	126	1	322
2009				
Segment profit				
Revenues	302	986	15	1,303
Purchased power	-	666	-	666
Operation, maintenance and administration	103	127	13	243
Depreciation and amortization	58	64	2	124
Income before financing charges and provision for payments in lieu of corporate income taxes	141	129	-	270
Financing charges				72
Income before provision for payments in lieu of corporate income taxes				198
Capital expenditures	187	148	1	336

(Canadian dollars in millions)	March 31, 2010	December 31, 2009
Total assets		
Transmission	9,106	9,118
Distribution	6,357	6,531
Other	1,475	161
	16,938	15,810

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

9. SUBSEQUENT EVENTS

On April 9, 2010, the Ontario Energy Board (OEB) released its decision regarding the 2010-2011 rate application made by Hydro One Networks in respect of its Distribution Business. The revised rates were approved for implementation on May 1, 2010 and January 1, 2011, respectively. On April 16, 2010, Hydro One Networks filed a draft rate order proposing revenue requirements of $1,146 million for 2010 and $1,236 million for 2011 which are expected to reflect increases of approximately 9.3% in 2010 and 10.5% in 2011 in support of necessary work programs, the implementation of the Green Energy Act and the installation of smart meters. On April 29, 2010, the OEB issued the final rate order for the 2010 distribution rates, which was consistent with the draft order filed on April 16, 2010. The 2011 rates will be finalized following the *Consensus Forecast* in September, 2010, when the 2011 return on equity will be forecasted.

On April 13, 2010, the OEB released its decision regarding the 2010 rate application made by Hydro One Brampton Networks Inc. under the OEB's second generation Incentive Regulation Mechanism (IRM). The revised rates, including the continuation of an amount of $1.00 per month per metered customer for smart meters, were approved for implementation on May 1, 2010.

On April 14, 2010, the OEB released its decision regarding 2010 rates of Hydro One Remotes Communities Inc. under the OEB's third generation IRM and approved an increase to basic rates for the generation and distribution of electricity of approximately 0.4%, effective May 1, 2010.

On April 26, 2010, the Company entered into four forward rate agreements in order to lock-in four interest rate resets on the floating rate it pays on $500 million of floating rate debt. The four forward rate agreements are classified as held-for-trading and measured at fair value.

On April 30, 2010, Hydro One Inc. exercised its option under its current Master Services Agreement (MSA) with Inergi LLP (Inergi) to renew for a further three-year period. The term of the current agreement, which expires on February 29, 2012, has been extended to February 28, 2015. Under the extended agreement, Inergi will provide business processing and information technology outsourcing services, as well as core system support related primarily to SAP implementation and optimization. Over the next five years of the MSA, total payments to Inergi for services will be about $650 million.